ACCESSION #: 9904300161

NON-PUBLIC?: N

LICENSEE EVENT REPORT (LER)

FACILITY NAME: Brunswick Steam Electric Plant (BSEP), PAGE: 1 OF 4

Unit No. 2

DOCKET NUMBER: 05000324

TITLE: Reactor Trip Due to Turbine Vibration Instrumentation

Failure

EVENT DATE: 03/29/1999 LER #: 1999-002-00 REPORT DATE: 04/28/1999

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 97

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:

50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:

NAME: Charles R. Elberfeld, Senior Analyst TELEPHONE: (910) 457-2136

Regulatory Affairs

COMPONENT FAILURE DESCRIPTION:

CAUSE: B SYSTEM: IV COMPONENT: VT MANUFACTURER: General

Electric

Company

REPORTABLE TO EPIX: Y

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On March 29, 1999, at 0837 hours, an invalid high vibration signal from a failed main turbine bearing vibration detector caused a main turbine trip which resulted in a Unit No. 2 reactor trip and subsequent Primary Containment Isolation system Group 2, 6, and 8 valve isolations/signals being initiated. Safety Relief Valves (SRVs) "F" and "G" lifted and immediately closed. At the time of the event, Unit No. 2 was operating at 97 percent of rated power. The SRV lifts were evaluated and it was determined that the momentary lifts were to be expected based on the impact of the transient on the reactor/steam lines.

The cause of the event is attributed to failed electrical connections on the vibration detector for the No. 9 main turbine bearing. The detector failure caused the invalid high vibration signal which initiated the event.

Checks of bearing temperatures, the vibration behavior of adjacent bearings, and bearing oil samples were made to ensure that an actual vibration problem did not exist. The vibration detector was replaced and the other detectors for the turbine bearings were checked and replaced as applicable. Monitoring necessary to detect vibration instrumentation failure precursors is being established. A multi-disciplined team is being formed to develop and implement options to eliminate the single point turbine high vibration trip.

This condition is being reported in accordance with 10 CFR 50.73(a)(2)(iv), as a condition that resulted in the actuations of

engineered safety features including the Reactor Protection system.

END OF ABSTRACT

Energy Industry Identification System (EIIS) codes are identified in the text as [XX].

INTRODUCTION

On March 29, 1999, at 0837 hours, an invalid high vibration signal from a failed vibration detector [VT] caused a main turbine trip which resulted in a Unit No. 2 reactor trip and subsequent Primary Containment Isolation system [JM] (PCIS) Group 2, 6, and 8 valve isolations/signals being initiated. Safety Relief Valves [RV] (SRVs) "F" and "G" lifted and immediately closed. At the time of the event, Unit No. 2 was operating at 97 percent of rated power. At 1135 hours, a four-hour non-emergency report (i.e., Event Number 35522) was made to the NRC in accordance with 10 CFR 50.72(b)(2)(ii). This condition is being reported in accordance with 10 CFR 50.73(a)(2)(iv), as a condition that resulted in the actuations of engineered safety features including the Reactor Protection system [JC] (RPS).

EVENT DESCRIPTION

On March 29, 1999, at approximately 0837 hours, the vibration instrumentation [IV], for the No. 9 bearing on the main turbine [TRB], generated an invalid high vibration signal which caused a main turbine trip. In turn, the main turbine trip resulted in the generation of

coincident reactor trip signals from the Turbine Stop Valve Closure, and Turbine Control Valve Fast Closure, Control Oil Pressure - Low, RPS instrumentation, and the reactor tripped. Following the reactor trip, a normal reactor coolant level transient occurred in which the level decreased to a minimum of approximately 150 inches above the top of active fuel. The level was below the Low Level 1 setpoint of 166 inches for PCIS Group 2, 6, and 8 valve isolations; the involved systems/components functioned as designed. SRVs "F' and "G" lifted and immediately closed. Operators responded to the condition in accordance with plant procedures. At approximately 0905 hours, the reactor mode switch was locked in the "Shutdown" position, and by 1014 hours, the applicable PCIS isolation signals were reset. It was determined that the main turbine trip was caused by a failed vibration detector (manufactured by the General Electric Company, Part No. 3S7700VB100A1) on the main turbine No. 9 bearing. The detector failure caused the invalid high vibration signal which initiated the event. Checks of bearing temperatures, the vibration behavior of adjacent bearings, and bearing oil samples were made to ensure that an actual vibration problem did not exist. The vibration detector was replaced and the other detectors for the turbine bearings were checked and replaced as applicable.

The SRV lifts were evaluated and it was determined that the momentary lifts were to be expected based on the impact of the transient on the reactor/steam lines. The setpoints for the SRVs that lifted were set at

approximately 1130 psig. Reactor vessel pressure instrumentation indicated that a maximum pressure of approximately 1040 psig was actually sensed in the reactor pressure vessel during the event. Steam line pressure instrumentation monitoring pressure down strewn of the SRVs indicated a pressure increase of short duration (i.e., approximately one second or less) which was determined to be a pressure wave reflected back through the steam lines due to the closing of the turbine stop/control valves at the time of the turbine trip.

On March 30, 1999, at 1848 hours, the reactor mode switch was placed in the "Startup" position. On March 31, 1999, at 1745 hours, the reactor mode switch was placed in the "Run" position, and on April 1, 1999, at 0307 hours, the generator was synchronized to the grid.

EVENT CAUSE

The cause of the event is attributed to failed electrical connections on the vibration detector for the No. 9 main turbine bearing. The trip logic for the main turbine high vibration trip for any one of the 10 bearings is one-out-of-one with a three-second time delay. The three-second time delay is considered to be a sufficient time to eliminate false trips without affecting turbine protection. The detector is attached to a shaft rider probe, which "rides" on the main turbine shaft and transfers physical vibration information through movement of a magnet and its field in a stationary coil contained inside the detector assembly. Preliminary

results indicated that the high vibration signal was caused by a failure of a spot welded wiring coil connection internal to the detector assembly. The other internal electrical coil connection exhibited excessive movement which caused intermittent breaks in the connection's current path. To determine what caused the failed and intermittent connections, the detector was sent to the Harris Energy and Environmental Center for evaluation. The results of the evaluation determined that the causes of the failed and intermittent coil connections could be attributed to excessive thread clearance during manufacture and insufficient thread engagement/lack of thread locking system where the detector internal suspension spring connects to the center post. The center post is mechanically connected to the suspension spring by the threaded connection and interfaces with the shaft rider probe. The "looseness" allowed probe movement to be transferred to the electrical connections which resulted in the failed/intermittent connection conditions.

CORRECTIVE ACTIONS

The vibration detector for the main turbine No. 9 bearing was replaced. The remaining bearing vibration detectors on the Unit No. 2 main turbine were inspected and another that had low resistance readings was replaced as a precautionary measure. Shaft rider probes were also checked and any identified as having potential for excess lateral movement were replaced. General Electric Power Generation Services has been made aware of the vibration detector failure.

The remaining Unit No. 2 vibration detectors with the affected part no., 3S7700VB100A1, that were not replaced during the resultant shutdown, will be replaced prior to the end of the current refueling outage (i.e., B214R1).

Monitoring necessary to detect main turbine vibration instrumentation failure precursors for Unit Nos. 1 and 2, and the basis for bypassing the turbine trip if an adverse trend is identified, are being established.

The information contained in the evaluation of this event will be included in the Turbine and Generator system notebooks and the maintenance rule database. These actions will sensitize new turbine and generator system engineers to the possibility of detector failures and the potential subsequent trip if abnormal/adverse trends are detected.

A team consisting of engineering, operations, and maintenance personnel will be established to develop and implement options to address the single point turbine high vibration turbine trip. Developed options will be presented to management for approval by September 29, 1999. Any additional long-term corrective actions to preclude recurrence will be based on the failure evaluation results and further review of industry experience.

SAFETY ASSESSMENT

The safety significance of this occurrence is considered minimal. This event is bounded by the limiting transient turbine trip without bypass,

which is addressed in Chapter 15 in the Updated Final Safety Analysis Report.

The plant equipment responded as designed to the event. As a result of the RPS actuation, all control rods fully inserted. The SRVs "F" and "G" momentarily lifted in response to a pressure wave in the steam lines. The SRV performance was evaluated and found to be acceptable. The PCIS system Group 2, 6, and 8 isolation signals were initiated as designed when the expected low reactor coolant level transient occurred after the reactor trip. Group 2 isolation valves include drywell equipment and floor drains, traversing in-core probe, residual beat removal (RER) discharge to radwaste, and RHR process sampling valves. Group 6 isolation valves include Containment Atmosphere Control system and Post Accident Monitoring valves. Group 8 isolation valves include RHR system shutdown cooling isolation valves, which were closed prior to the initiation of the isolation signal.

PREVIOUS SIMILAR EVENTS

No previous similar events have been identified. ATTACHMENT 1 TO 9904300161
PAGE 1 OF 2

CP&L

Carolina Power & Light Company

P.O. Box 10429

Southport, NC 28461-0429

April 28, 1999 10 CFR 50.73

SERIAL: BSEP 99-0067

U. S. Nuclear Regulatory Commission

ATTN: Document Control Desk

Washington, DC 20555-0001

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NO. 2

DOCKET NO. 50-324

LICENSE NO. DPR-62

LICENSEE EVENT REPORT 2-99-002

Gentlemen:

In accordance with the Code of Federal Regulations, Title 10, Part 50.73, Carolina Power & Light Company submits the enclosed Licensee Event Report. This report fulfills the requirement for a written report within thirty (30) days of a reportable occurrence. No regulatory commitments are contained in this submittal.

Please refer any questions regarding this submittal to Mr. Keith R. Jury, Manager - Regulatory Affairs, at (910) 457-2783.

Sincerely,

Jeffrey J. Lyash

Plant General Manager

Brunswick Steam Electric Plant

CRE/cre

Enclosure: Licensee Event Report

cc (with enclosure):

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